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Hanging liners by pipe expansion

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HANGING LINERS BY PIPE EXPANSION

The field of this invention relates to suspending one tubular in another, especially hanging liners which are to be cemented.

In completing wellbores, frequently a liner is inserted into casing and suspended from the casing by a liner hanger. Various designs of liner hangers are known and generally involve a gripping mechanism, such as slips, and a sealing mechanism, such as a packer which can be of a variety of designs. The objective is to suspend the liner during a cementing procedure and set the packer for sealing between the liner and the casing. Liner hanger assemblies are expensive and provide some uncertainty as to their operation downhole.

Some of the objects of the preferred embodiment are to accomplish the functions of the known liner hangers by alternative means, thus eliminating the traditionally known liner hanger altogether while accomplishing its functional purposes at the same time in a single trip into the well. Another objective of the preferred embodiment is to provide alternate techniques which can be used to suspend one tubular in another while facilitating a cementing operation and still providing a technique for sealing the tubulars together. Various fishing tools are known which can be used to support a liner being inserted

into a larger tubular. One such device is made by Baker Oil Tools and known as a "Tri-State Type B Casing and Tubing Spear," Product No. 126-09. In addition to known spears which can support a tubing string for lowering into a wellbore, techniques have been developed for expansion of tubulars downhole. Some of the techniques known in the prior art for expansion of tubulars downhole are illustrated in U.S. Patents 4,976,322; 5,083,608; 5,119,661; 5,348,095; 5,366,012; and 5,667,011.

According to a first aspect of the present invention there is provided a method as claimed in claim 1.

According to a second aspect of the present invention there is provided a method as claimed in claim 7.

Various embodiments of the present invention together with other arrangements given for illustrative purposes only will now be described, by way of example only, and with reference to the accompanying drawings in which:

Figures 1-4 are a sectional elevation, showing a first embodiment of the method to suspend, cement and seal one tubular to another downhole, using pipe expansion techniques.

Figures 5-11a are another embodiment creating longitudinal passages for passage of the cementing material prior to sealing the tubulars together.

Figures 12-15 illustrate yet another embodiment incorporating a sliding sleeve valve for facilitating the cementing step.

Figures 16-19 illustrate the use of a grapple technique to suspend the tubular inside a bigger tubular, leaving spaces between the grappling members for passage of cement prior to sealing between the tubulars.

Figures 20-26 illustrate an alternative embodiment involving a sequential flaring of the inner tubular from the bottom up.

Figures 28-30 illustrate an alternative embodiment involving fabrication of the tubular to be inserted to its finished dimension, followed by collapsing it for insertion followed by sequential expansion of it for completion of the operation.

Referring to Figure 1, a tubular **10** is supported in casing **12**, using known techniques such as a spear made by Baker Oil Tools, as previously described. That spear or other gripping device is attached to a running string **14**. Also located on the running string **14** above the spear is a hydraulic or other type of stroking mechanism which will allow relative movement of a swage assembly **16** which moves in tandem with a portion of the running string **14** when the piston/cylinder combination (not shown) is actuated, bringing the swage **16** down toward the upper end **18** of the tubular **10**. As shown in Figure 1 during run-in, the tubular **10** easily fits through the casing **12**. The tubular **10** also comprises one or more openings **20** to allow the cement to pass through, as will be explained below. Comparing Figure 2 to Figure 1, the tubular **10** has been expanded radially at its upper end **18** so that a segment **22** is in contact with the casing **12**. Segment **22** does not include the openings **20**; thus, an annular space **24** exists around the outside of the tubular **10** and inside of the casing **12**. While in the position shown in Figure 2, cementing can occur. This procedure involves pumping cement through the tubular **10** down to its lower end where it can come up and around

into the annulus **24** through the openings **20** so that the exterior of the tubular **10** can be fully surrounded with cement up to and including a portion of the casing **12**. Before the cement sets, the piston/ cylinder mechanism (not shown) is further actuated so that the swage assembly **16** moves further downwardly, as shown in Figure 3. Segment **22** has now grown in Figure 3 so that it encompasses the openings **20**. In essence, segment **22** which is now against the casing **12** also includes the openings **20**, thereby sealing them off. The seal can be accomplished by the mere physical expansion of segment **22** against the casing **12**. Alternatively, a ring seal **26** can be placed below the openings **20** so as to seal the cemented annulus **24** away from the openings **20**. Optionally, the ring seal **26** can be a rounded ring that circumscribes each of the openings **20**. Additionally, a secondary ring seal similar to **26** can be placed around the segment **22** above the openings **20**. As shown in Figure 3, the assembly is now fully set against the casing **12**. The openings **20** are sealed and the tubular **10** is fully supported in the casing **12** by the extended segment **22**. Referring to Figure 4, the swage assembly **16**, as well as the piston/cylinder assembly (not shown) and the spear which was used to support the tubular **10**, are removed with the running string **14** so that what remains is the tubular **10** fully cemented and supported in the casing **12**. The entire operation has been accomplished in a single trip. Further completion operations in the wellbore are now possible. Currently, this embodiment is preferred.

Figures 5–12 illustrate an alternative embodiment. Here again, the tubular **28** is supported in a like manner as shown in Figures 1–4, except that the swage assembly **30** has a different configuration. The swage assembly

30 has a lower end 32 which is best seen in cross-section in Figure 8. Lower end 32 has a square or rectangular shape which, when forced against the tubular 28, leaves certain passages 34 between itself and the casing 36. Now referring to Figure 7, it can be seen that when the lower end 32 is brought inside the upper end 38 of the tubular 28, the passages 34 allow communication to annulus 40 so that cementing can take place with the pumped cement going back up the annulus 40 through the passages 34. Referring to Figure 8, it can be seen that the tubular 28 has four locations 42 which are in contact with the casing 36. This longitudinal surface location in contact with the casing 36 provides full support for the tubular 28 during the cementing step. Thus, while the locations 42 press against the inside wall of the casing 36 to support the tubular 28, the cementing procedure can be undertaken in a known manner. At the conclusion of the cementing operation, an upper end 44 of the swage assembly 30 is brought down into the upper end 38 of the tubular 28. The profile of the upper end 44 is seen in Figure 10. It has four locations 46 which protrude outwardly. Each of the locations 46 encounters a mid-point 48 (see Figure 8) of the upper end 38 of the tubular 28. Thus, when the upper end 44 of the swage assembly 30 is brought down into the tubular 28, it reconfigures the shape of the upper end 38 of the tubular 28 from the square pattern shown in Figure 8 to the round pattern shown in Figure 12. Figure 11 shows the running assembly and the swage assembly 30 removed, and the well now ready for the balance of the completion operations. The operation has been accomplished in a single trip into the wellbore. Accordingly, the principal difference in the embodiment shown in Figures 1-4 and that shown in Figures 5-12 is that the first embodiment employed holes

or openings to facilitate the flow of cement, while the second embodiment provides passages for the cement with a two-step expansion of the upper end 38 of the tubular 28. The first step creates the passages 34 using the lower end 32 of the swage assembly 30. It also secures the tubular 28 to the casing 36 at locations 42. After cementing, the upper end 44 of the swage assembly 30 basically finishes the expansion of the upper end 38 of the tubular 28 into a round shape shown in Figure 12. At that point, the tubular 28 is fully supported in the casing 36. Seals, as previously described, can optionally be placed between the tubular 28 and the casing 36 .

Another embodiment is illustrated in Figures 12-15. This embodiment has similarities to the embodiment shown in Figures 1-4. One difference is that there is now a sliding sleeve valve 48 which is shown in the open position exposing openings 50. As shown in Figure 12, a swage assembly 52 fully expands the upper end 54 of the tubular 56 against the casing 58, just short of openings 50. This is seen in Figure 13. At this point, the tubular 56 is fully supported in the casing 58. Since the openings 50 are exposed with the sliding sleeve valve 48, cementing can now take place. At the conclusion of the cementing step, the sliding sleeve valve 48 is actuated in a known manner to close it off, as shown in Figure 14. Optionally, seals can be used between tubular 56 and casing 58. The running assembly, including the swage assembly 52, is then removed from the tubular 56 and the casing 58, as shown in Figure 15. Again, the procedure is accomplished in a single trip. Completion operations can now continue in the wellbore.

Figures 16–19 illustrate another technique. The initial support of the tubular **60** to the casing **62** is accomplished by forcing a grapple member **64** down into an annular space **66** such that its teeth **68** ratchet down over teeth **70**, thus forcing teeth **72**, which are on the opposite side of the grappling member **64** from teeth **68**, to fully engage the inner wall **74** of the casing **62**. This position is shown in Figure 17, where the teeth **68** and **70** have engaged, thus supporting the tubular **60** in the casing **62** by forcing the teeth **72** to dig into the inner wall **74** of the casing **62**. The grapple members **64** are elongated structures that are placed in a spaced relationship as shown in Figure 17A. The spaces **76** are shown between the grapple members **64**. Thus, passages **76** provide the avenue for cement to come up around annulus **78** toward the upper end **80** of the tubular **60**. At the conclusion of the cementing, the swage assembly **82** is brought down into the upper end **80** of the tubular **60** to flare it outwardly into sealing contact with the inside wall **74** of the casing **62**, as shown in Figure 18. Again, a seal can be used optionally between the upper end **80** and the casing **62** to seal in addition to the forcing of the upper end **80** against the inner wall **74**, shown in Figure 18. The running assembly as well as the swage assembly **82** is shown fully removed in Figure 19 and further downhole completion operations can be concluded. All the steps are accomplished in a single trip.

Figures 20–25 illustrate yet another alternative of the present invention. In this situation, the swage assembly **84** has an upper end **86** and a lower end **88**. In the run-in position shown in Figure **20**, the upper end **86** is located below a flared out portion **90** of the tubular **92**. Located above the upper end **86** is a sleeve **94** which is preferably made of a softer material than the tubular

92, such as aluminum, for example. The outside diameter of the flared out segment **90** is still less than the inside diameter **96** of the casing **98**. Ultimately, the flared out portion **90** is to be expanded, as shown in Figure 21, into contact with the inside wall of the casing **98**. Since that distance representing that expansion cannot physically be accomplished by the upper end **96** because of its placement below the flared out portion **90**, the sleeve **94** is employed to transfer the radially expanding force to make initial contact with the inner wall of casing **98**. The upper end **86** of the swage assembly **84** has the shape shown in Figure 22 so that several sections **100** of the tubular **92** will be forced against the casing **98**, leaving longitudinal gaps **102** for passage of cement. In the position shown in Figures 21 and 22, the passages **102** are in position and the sections **100** which have been forced against the casing **98** fully support the tubular **92**. At the conclusion of the cementing operation, the lower segment **88** comes into contact with sleeve **94**. The shape of lower end **88** is such so as to fully round out the flared out portion **90** by engaging mid-points **104** of the flared out portion **90** (see Figure 22) such that the passages **102** are eliminated as the sleeve **94** and the flared out portion **90** are in tandem pressed in a manner to fully round them, leaving the flared out portion **90** rigidly against the inside wall of the casing **98**. This is shown in Figure 23. Figure 25 illustrates the removal of the swage assembly **84** and the tubular **92** fully engaged and cemented to the casing **98** so that further completion operations can take place. Figures 24 and 26 fully illustrate the flared out portion **90** pushed hard against the casing **98**. Again, in this embodiment as in all the others, auxiliary sealing devices can be used be-

tween the tubular **92** and the casing **98** and the process is done in a single trip.

Referring now to Figures 27-30, yet another embodiment is illustrated. Again, the similarities in the running in procedure will not be repeated because they are identical to the previously described embodiments. In this situation, the tubular **106** is initially formed with a flared out section **108**. The diameter of the outer surface **110** is initially produced to be the finished diameter desired for support of the tubular **106** in a casing **112** (see Figure 28) in which it is to be inserted. However, prior to the insertion into the casing **112** and as shown in Figure 28, the flared out section **108** is corrugated to reduce its outside diameter so that it can run through the inside diameter of the casing **112**. The manner of corrugation or other diameter-reducing technique can be any one of a variety of different ways so long as the overall profile is such that it will pass through the casing **112**. Using a swage assembly of the type previously described, which is in a shape conforming to the corrugations illustrated in Figure 28 but tapered to a somewhat larger dimension, the shape shown in Figure 29 is attained. The shape in Figure 29 is similar to that in Figure 28 except that the overall dimensions have been increased to the point that there are locations **114** in contact with the casing **112**. These longitudinal contacts in several locations, as shown in Figure 29, fully support the tubular **106** in the casing **112** and leave passages **116** for the flow of cement. The swage assembly can be akin to that used in Figures 5-11 in the sense that the corrugated shape now in contact with the casing **112** shown in Figures 29 at locations **114** can be made into a round shape at the conclusion of the cementing operation. Thus, a second portion of the swage assembly as

previously described is used to contact the flared out portion 108 in the areas where it is still bent, defining passages 116, to push those radially outwardly until a perfect full 360° contact is achieved between the flared out section 108 and the casing 112, as shown in Figure 30. This is all done in a single trip.

Those skilled in the art can readily appreciate that various embodiments have been disclosed which allow a tubular, such as 10, to be suspended in a running assembly. The running assembly is of a known design and has the capability not only of supporting the tubular for run-in but also to actuate a swage assembly of the type shown, for example, in Figure 1 as item 16. What is common to all these techniques is that the tubular is first made to be supported by the casing due to a physical expansion technique. The cementing takes place next and the cementing passages are then closed off. Since it is important to allow passages for the flow of cement, the apparatus of the present invention, in its various embodiments, provides a technique which allows this to happen with the tubular supported while subsequently closing them off. The technique can work with a swage assembly which is moved downwardly into the top end of the tubular or in another embodiment, such as shown in Figures 20–26, the swage assembly is moved upwardly, out of the top end of the tubular. The creation of passages for the cement, such as 34 in Figure 8, 76 in Figure 17A, or 102 in Figure 22, can be accomplished in a variety of ways. The nature of the initial contact used to support the tubular in the casing can vary. Thus, although four locations are illustrated for the initial support contact in Figure 8, a different number of such locations can be used. Different materials can be used to encase the liner up

and into the casing from which it is suspended, including cement, blast furnace slag, or other materials. Known techniques are used for operating the sliding sleeve valve shown in Figure 12-15, which selectively exposes the openings **50**. Other types of known valve assemblies are also contemplated. Despite the variations, the technique winds up being a one-trip operation.

Those skilled in the art will now appreciate that what has been disclosed is a method which can completely replace known liner hangers and allows for sealing and suspension of tubulars in larger tubulars, with the flexibility of cementing or otherwise encasing the inserted tubular into the larger tubular.

The foregoing disclosure and description of the invention are illustrative and explanatory thereof, and various changes in the size, shape and materials, as well as in the details of the illustrated construction, may be made.

Claims

1. A method of completing a well, comprising:
running in a tubular string into a cased borehole;
expanding a portion of said tubular into supporting contact with the casing;
delivering a sealing material through at least one opening in said tubular, with said tubular so supported;
closing off said opening.

2. The method of claim 1, further comprising:
expanding said tubular to accomplish said closure after said delivering of said sealing material.

3. The method of claim 2, further comprising:
using said expanding to close off said opening to accomplish a seal between said tubular and said casing.

4. The method of claim 3, further comprising:
providing a seal downhole of said opening as a backup seal to any seal formed by said expanding.

5. The method of claim 1, further comprising:
pushing said opening against the casing to close it.

6. The method of claim 2, further comprising:
accomplishing said running in, supporting, delivering a sealing material, and closing of said opening by expansion, all in a single trip into the well.

7. A method of completing a well, comprising:
running a tubular string into a cased borehole;
expanding portions of said tubular string into

contact with the casing for support thereof;

leaving gaps between said tubular string and said casing, with said tubular string supported to said casing;

using said gaps for passage of a sealing material;

closing said gaps.

8. The method of claim 7, further comprising:

providing longitudinal contact between said tubular string and said cased borehole;

defining said gaps as passages between said longitudinal contacts between said tubular string and said cased wellbore.

9. The method of claim 8, further comprising:

using a fluted expansion swage to create said longitudinal contact for support of said tubular string;

providing offset flutes on said swage, located one above another;

using lowermost flutes to create said longitudinal contact;

using offset flutes to subsequently remove said gaps after passage of said sealing material.

10. The method of claim 9, further comprising:

offsetting said offset flutes about 90° from said lowermost flutes.

11. The method of claim 7, further comprising:

accomplishing said running in, expanding, leaving gaps, passage of said sealing material, and closing said gaps in a single trip into the wellbore.

12. The method of claim 7, further comprising:

providing a seal between said tubular string and said cased borehole by said closing of said gaps.

13. The method of claim 1, further comprising: using full circumferential contact for said supporting contact.

14. The method of claim 13, further comprising:
providing a valve with said opening;
operating said valve to close off said opening.

15. The method of claim 14, further comprising: providing a sliding sleeve on said tubular string as said valve.

16. The method of claim 7, further comprising:
running in with a swage inside said tubular string;
supporting said tubular string while moving said swage uphole to expand portions of said tubular string into contact with said cased borehole for support thereof.

17. The method of claim 16, further comprising:
locating a force transfer member inside said tubular string during run-in;
transferring an expansion force from said swage through said force transfer member to said tubular string for said expansion into said cased borehole for support thereof.

18. The method of claim 17, further comprising: configuring said swage to force said gaps closing through a force transfer through a sleeve which serves as said force transfer member.

19. The method of claim 9, further comprising:
running in with a swage inside said tubular string;
supporting said tubular string while moving said swage uphole to expand portions of said tubular string into contact with said cased borehole for support

thereof.

20. The method of claim 19, further comprising:
locating a force transfer member inside said tubular string during run-in;
transferring an expansion force from said swage through said force transfer member to said tubular string for said expansion into said cased borehole for support thereof.

21. The method of claim 20, further comprising:
configuring said swage to force said gaps closed through a force transfer through a sleeve which serves as said force transfer member.

22. The method of claim 7, further comprising:
reducing the diameter of a part of a tubing string whose original dimension, on said part thereof, was at least as large as the inside diameter of a cased wellbore, to an outer dimension small enough to fit into said cased borehole.

23. The method of claim 22, further comprising:
expanding said portion of said tubing string to its said original dimension to close said gaps;
providing said original dimension as larger than the inside dimension of said cased wellbore;
sealing between said tubing string and said cased wellbore by forcing said portion of said tubular string into circumferential contact with said cased wellbore.

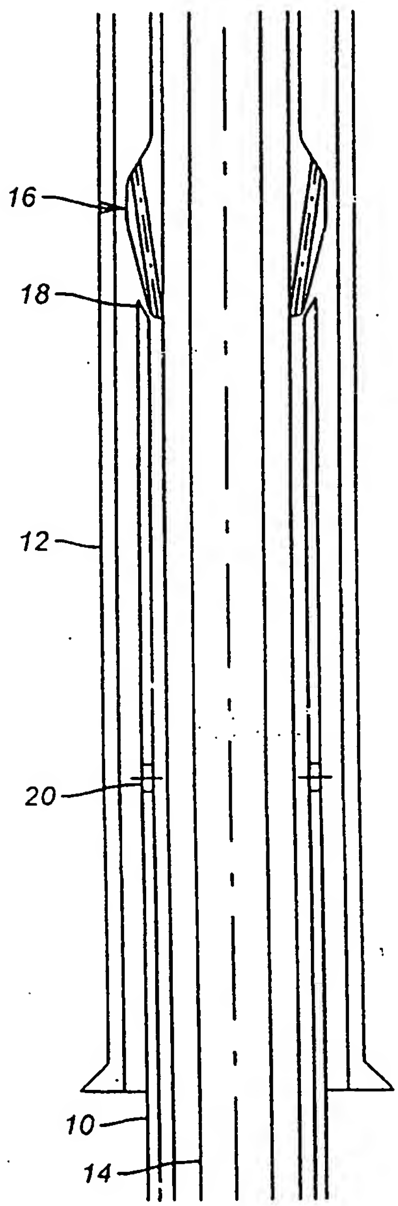

FIG. 1

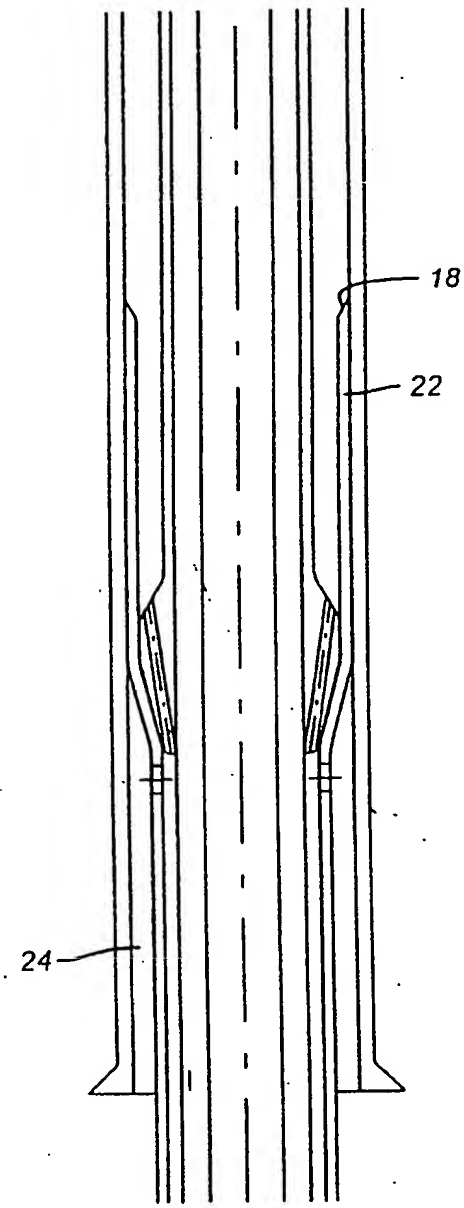

FIG. 2

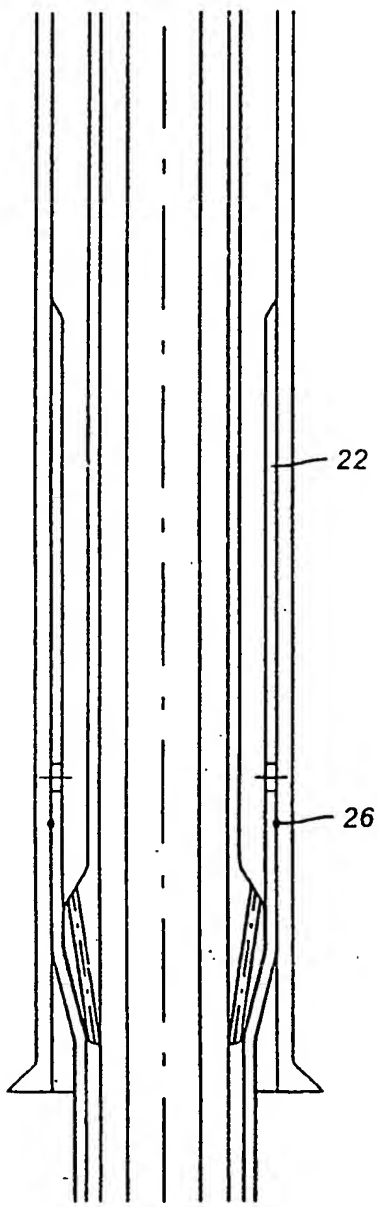

FIG. 3

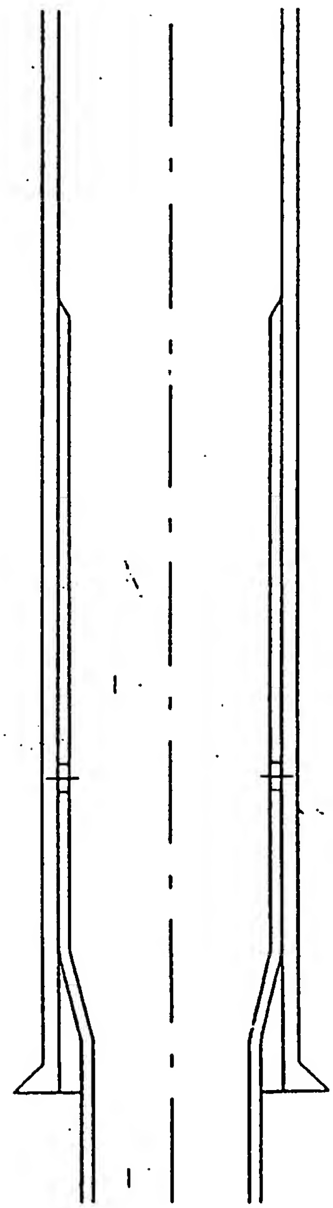

FIG. 4

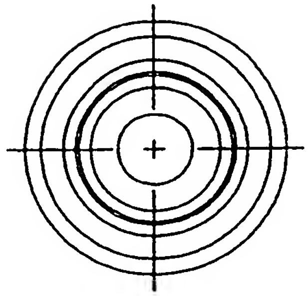

FIG. 6

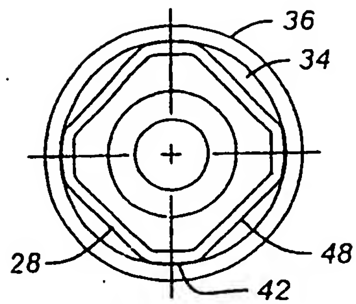

FIG. 8

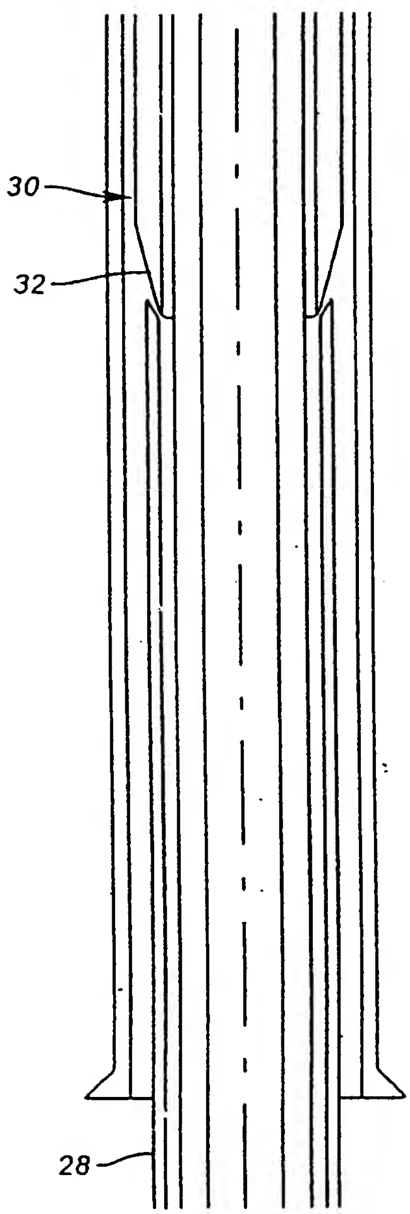

FIG. 5

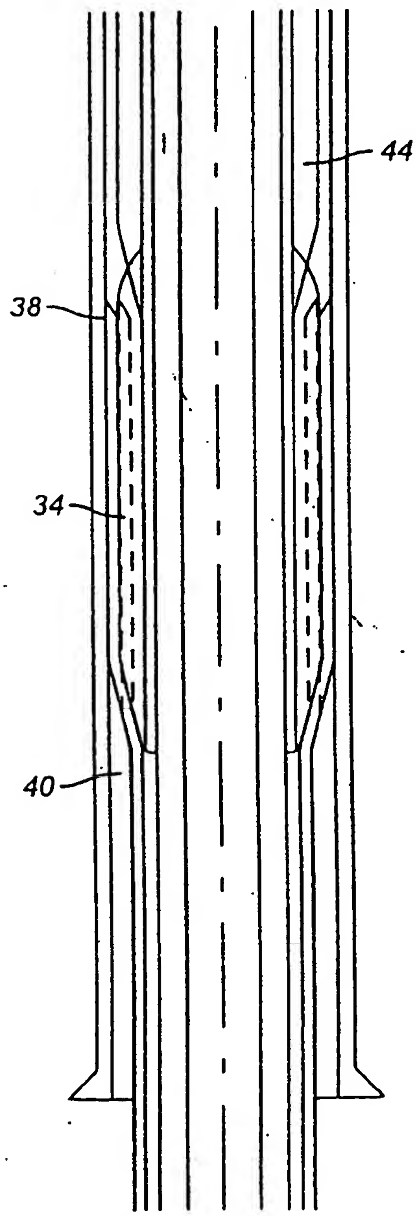

FIG. 7

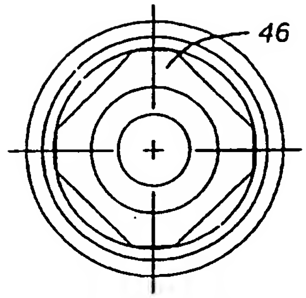

FIG. 10

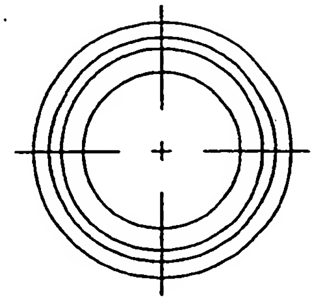

FIG. 11a

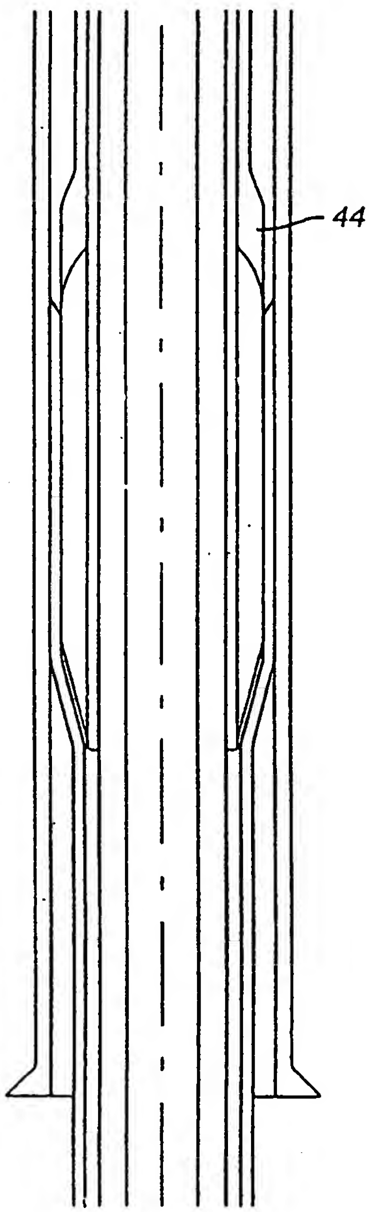

FIG. 9

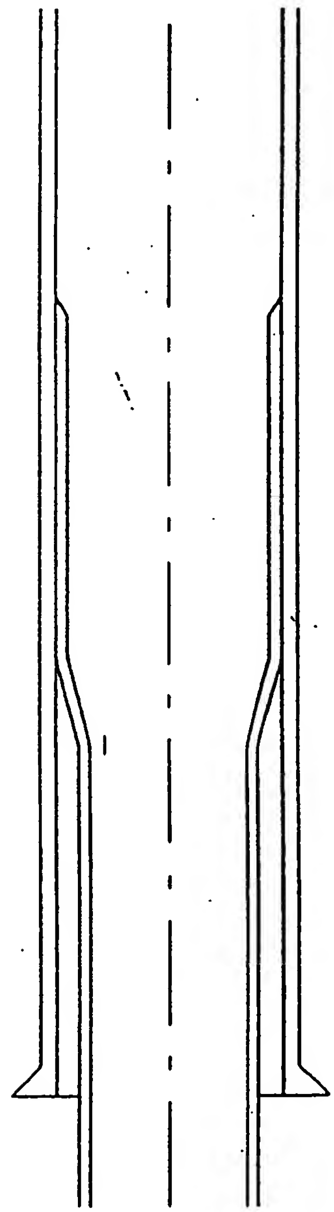

FIG. 10

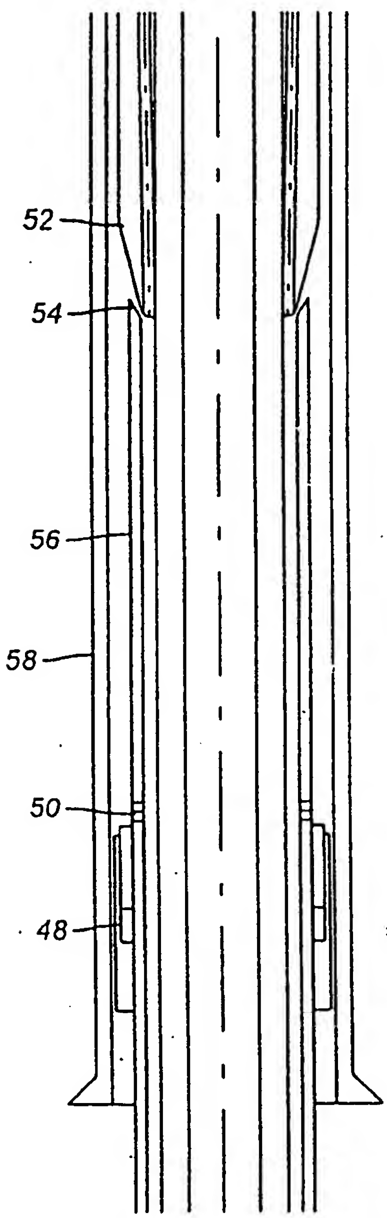

FIG. 12

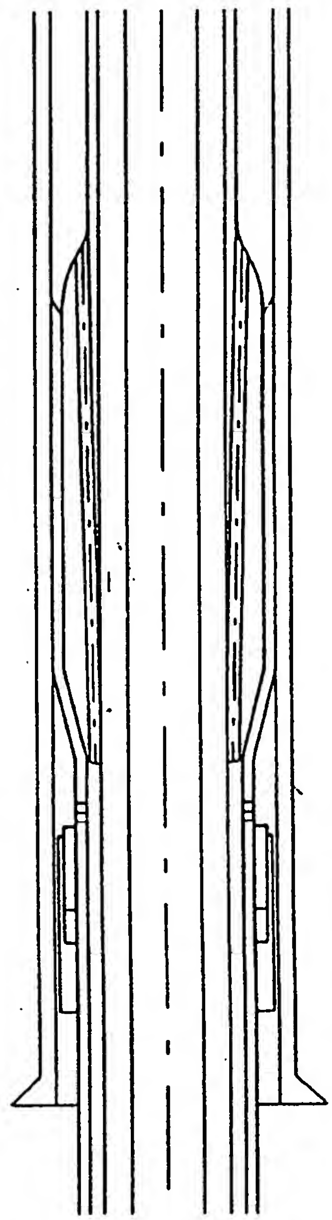

FIG. 13

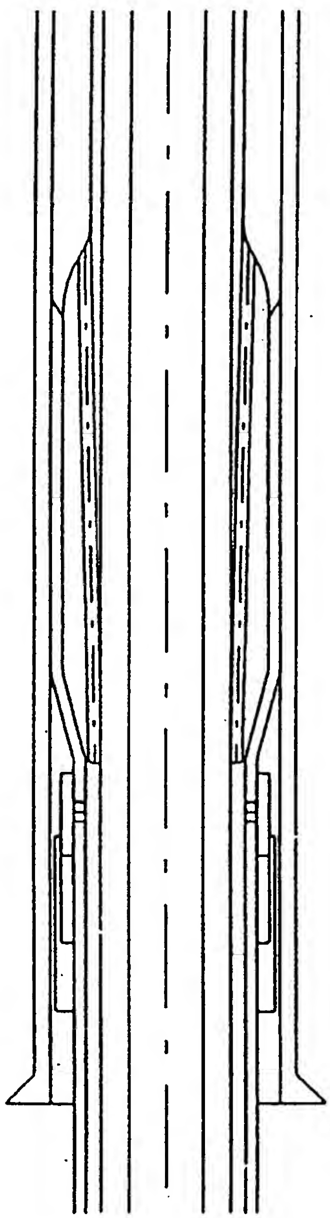

FIG. 14

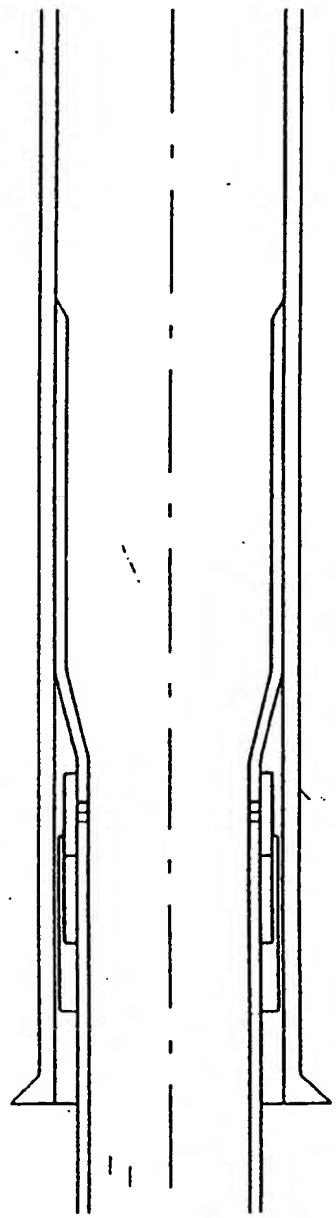

FIG. 15

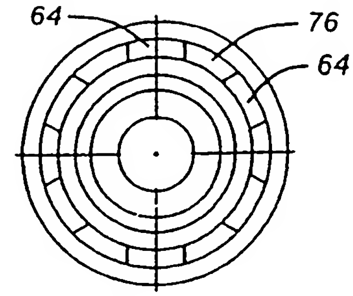

FIG. 17a

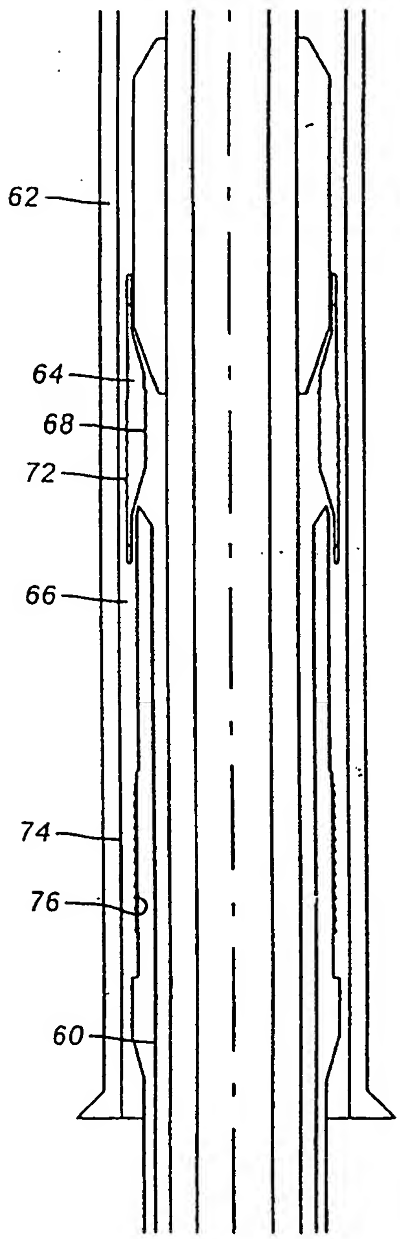

FIG. 16

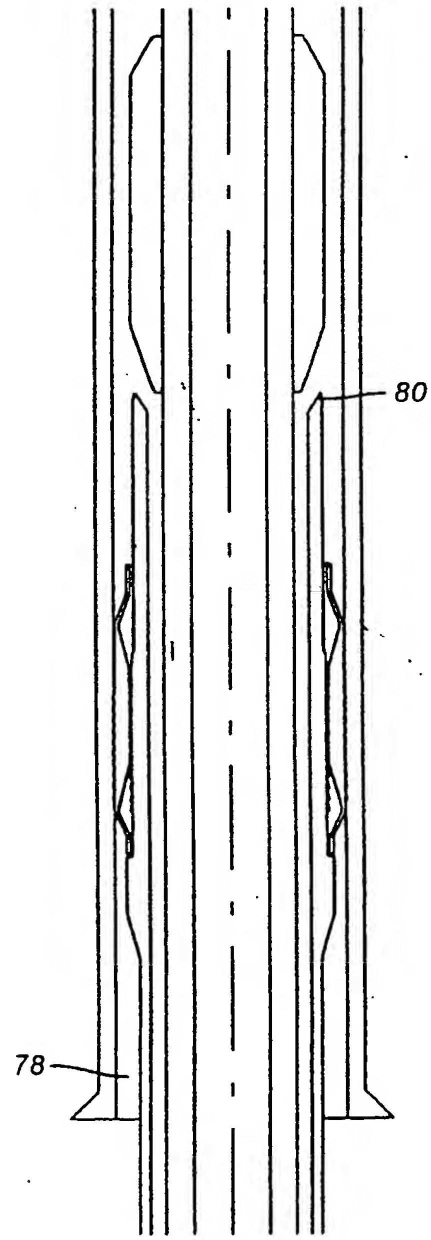

FIG. 17

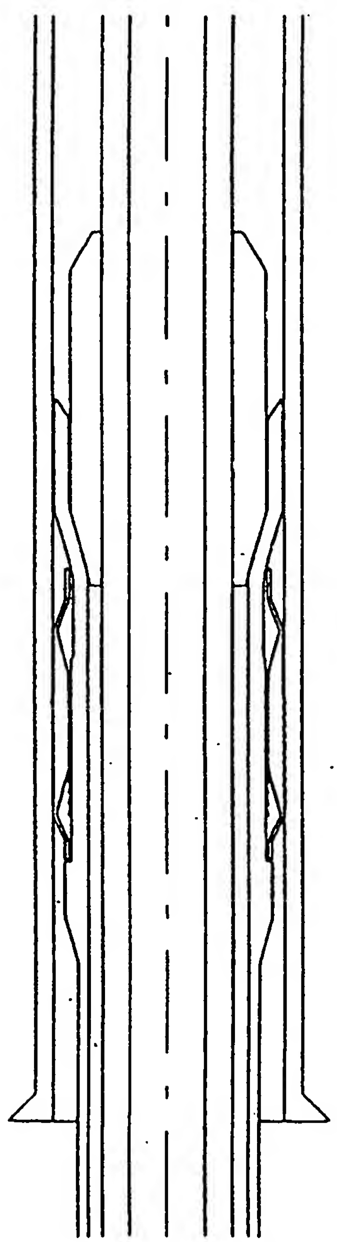

FIG. 18

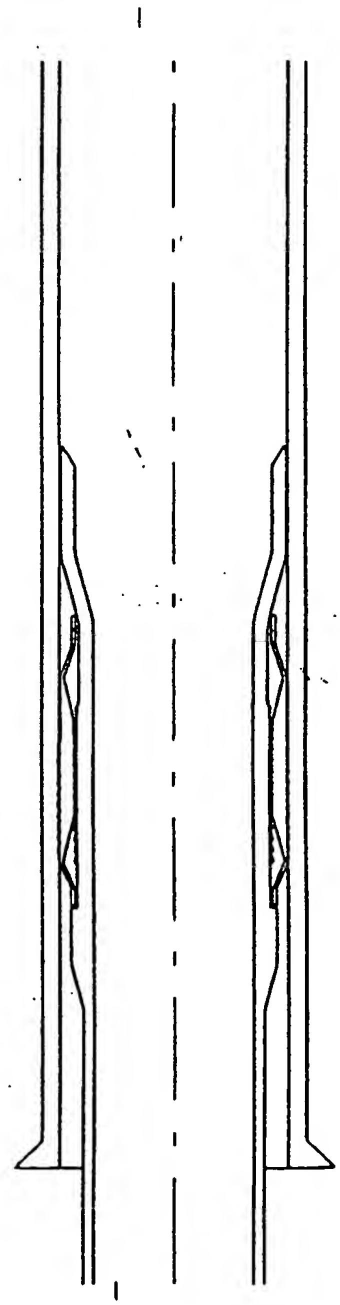

FIG. 19

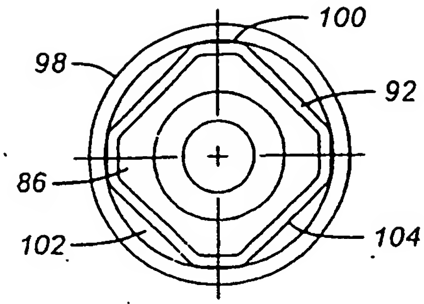

FIG. 22

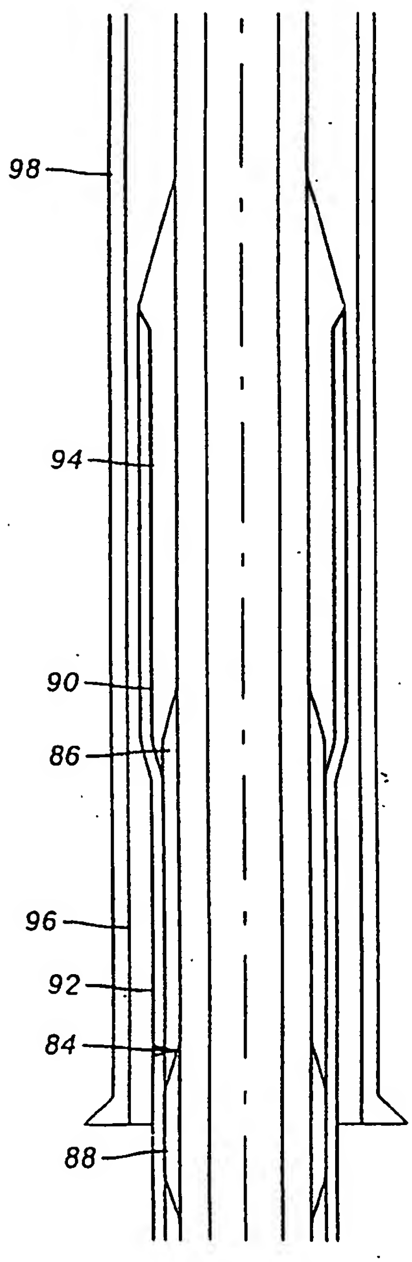

FIG. 20

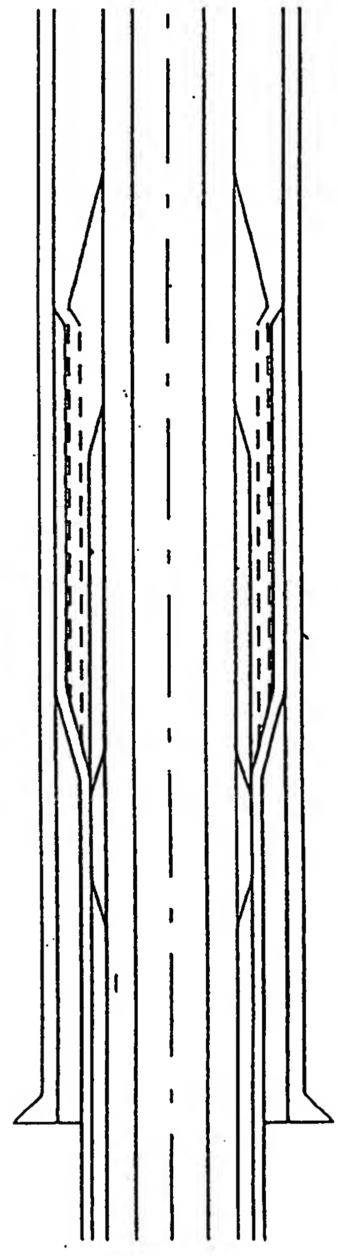

FIG. 21

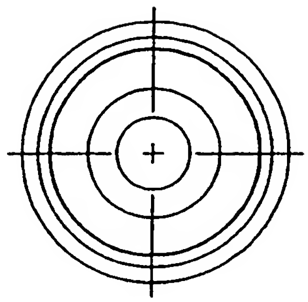

FIG. 24

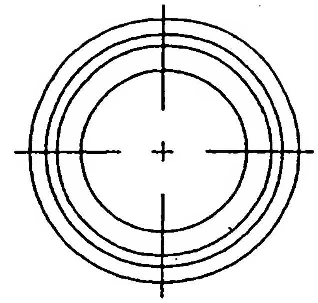

FIG. 26

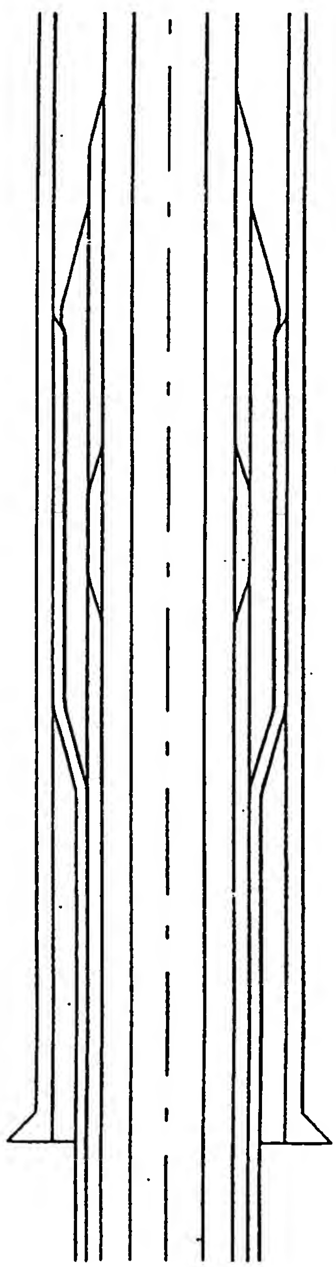

FIG. 23

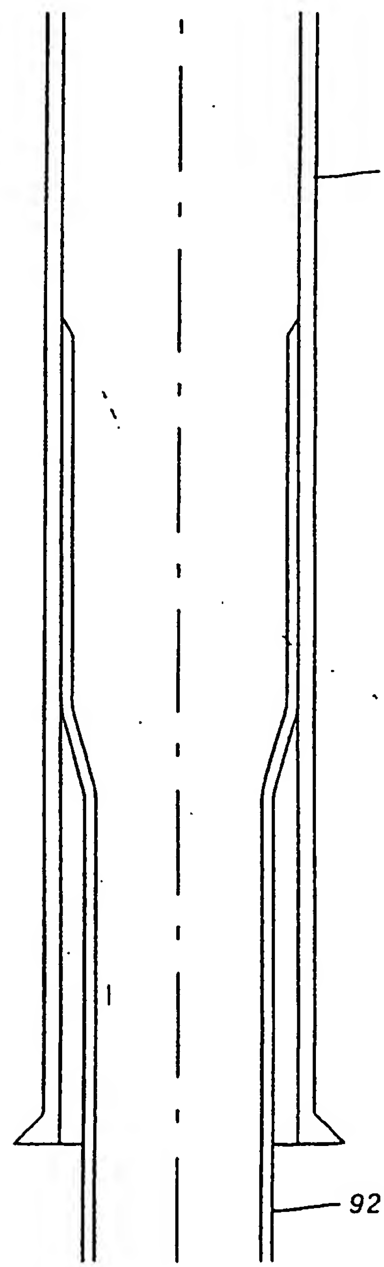

FIG. 25

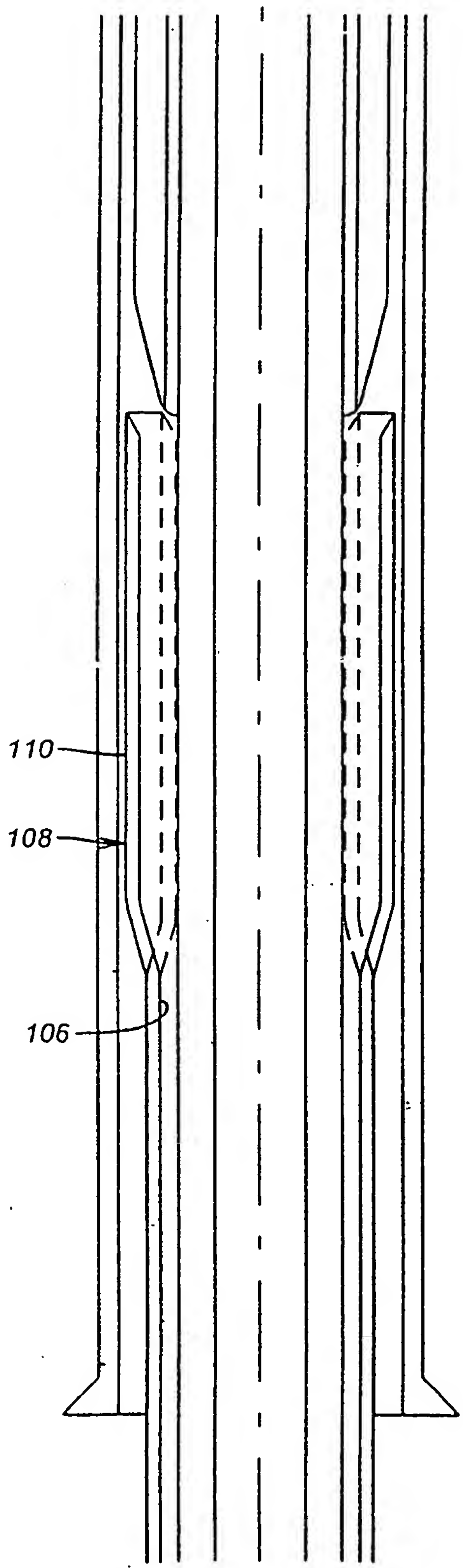

FIG. 27

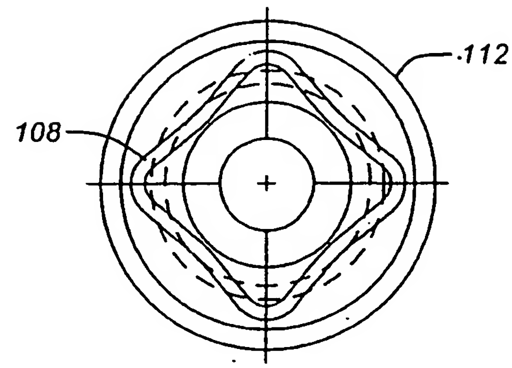

FIG. 28

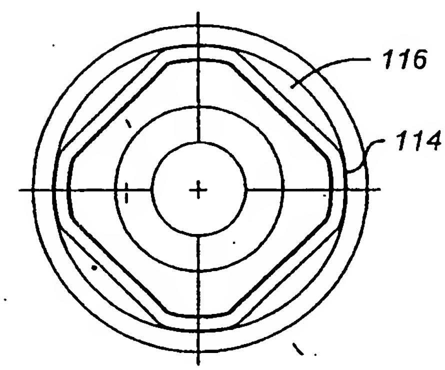

FIG. 29

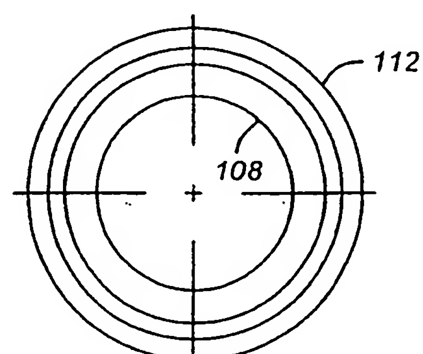

FIG. 30

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